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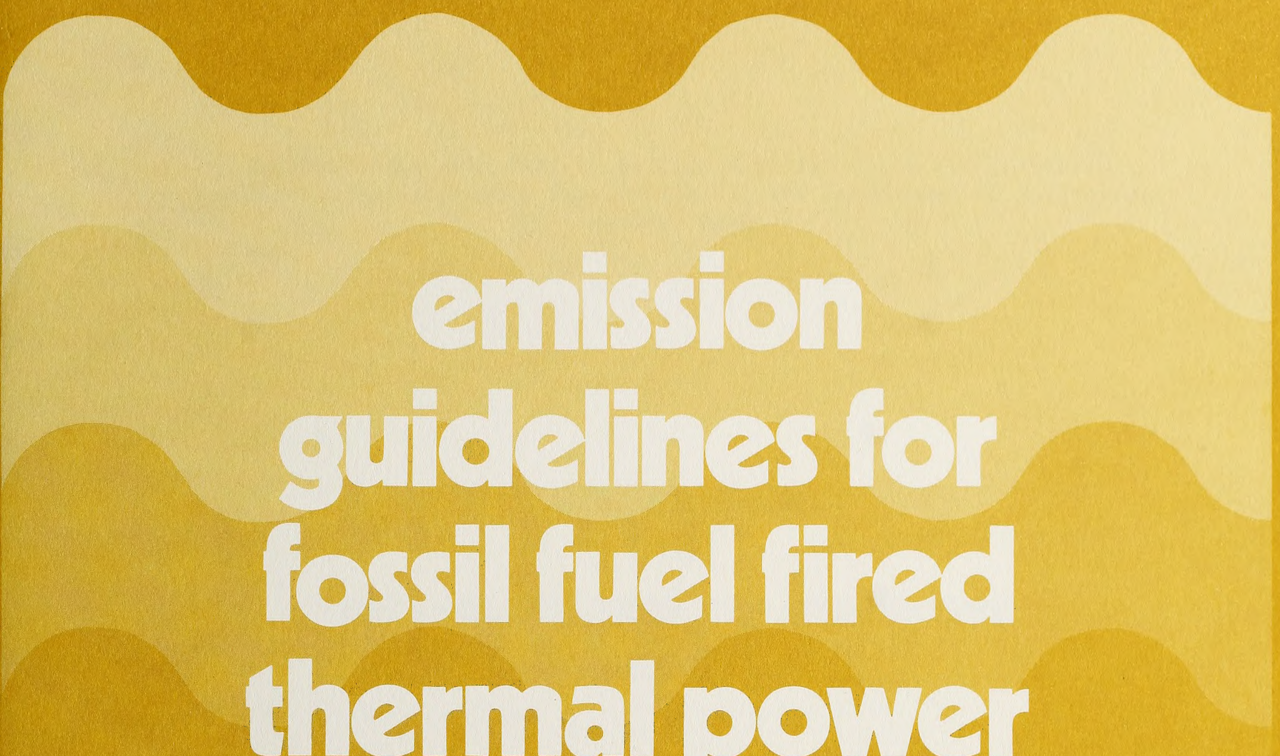

emission guidelines for fossil fuel fired thermal power generating plants in alberta

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In accordance with Part 1, Section 4 of the Clean Air (General) Regulations being Alberta Statute 216/75, the Department of Environment hereby issues

EMISSION GUIDELINES

for

FOSSIL FUEL FIRED THERMAL POWER GENERATING PLANTS

IN ALBERTA

Prepared by:
Air Quality Branch
Standards and Approvals Division
Alberta Environment
April, 1984

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Introduction

1.0 The Department of the Environment herein presents emission guidelines for new fossil fuel-fired thermal power generating plants in Alberta. This document, pursuant to Section 4 of the Clean Air (General) Regulations, specifies emission limits for particulate matter, oxides of nitrogen (NO_x) and sulphur dioxide (SO_2) in an effluent stream from an affected facility. All existing and other sources not covered under these guidelines, will remain subject to existing regulations. The requirements discussed in these guidelines are intended to minimize the effect of the thermal power generating industry on ambient air quality.

1.1 The emission limits are based on

(a) the best practicable technology (BPT) to reduce emissions of particulate matter and NO_x, and

(b) the best practicable system to reduce emissions of SO_2 that includes

(i) the use of low sulphur containing fuels emitting SO_2 not in excess of 258 ng/J, or
(ii) the use of "BPT" for high sulphur containing fuels.

1.2 Supporting information used by the Department in developing these guidelines are given in a separate document, "Support Document for the Thermal Power Plants' Guidelines".

1.3 Manual source emission surveys are required for compliance with limits based on a short term averaging period for particulate matter, oxides of nitrogen and sulphur dioxide using reference methods specified in Appendix A.

1.4 Continuous source emission monitoring (CSEM) systems are also required for nitrogen oxide, sulphur dioxide, oxygen or carbon dioxide and opacity. Performance specifications and location criteria for each CSEM system are given in Appendix B. Each CSEM system has to be operational at least 75 percent of the time in any 30 successive days of boiler operation, to determine compliance with NO_x and SO_2 emission limits based on a 720-hour rolling averaging period. However, other alternate methods specified in Appendix A can be used to supplement the minimum data required for continuous compliance determination.

1.5 A continuous source emission monitoring system to measure opacity is required to assure proper operation and maintenance of the emission control system but is not used for continuous compliance determination. Compliance with the opacity limit is determined by the use of the method specified in VEE-2/77.

1.6 Ambient air quality requirements are the same as specified in the Clean Air (Maximum Levels) Regulations and ambient monitoring will be specified in each plant's Licence to Operate or Use. Monitoring information collected is to be reported as per AMD-77-1.

1.7 These guidelines also specify

(a) compliance determination procedures and methods, and

(b) reporting requirements for source emission monitoring.

Application

2.0 These guidelines apply to each fossil fuel fired steam generating unit

a) that is capable of combusting more than 73 mega watts (250 million BTU/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

b) for which initial approval to construct is granted by the ERCB after May 1, 1981.

2.1 These guidelines also apply to electric utility combined cycle gas turbines that are capable of combusting more than 73 mega watts (250 million BTU/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to these guidelines.

2.2 These guidelines do not apply to the following sources:

(a) all existing thermal power generating plants,

(b) all thermal power generating units under construction for which ERCB approval was granted prior to May 1, 1981, and

(c) all gas turbines.

Definitions

3.0 In these guidelines,

"available system capacity" means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity;

"combined cycle gas turbine" means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit;

"continuous source emission monitoring system" means all the equipment used for sampling, conditioning and analyzing emissions or process parameters and for recording data;

"electric utility company" means any interconnected organization, business, or governmental entity that generates electric power for sale (e.g. TransAlta Utilities Corporation, Edmonton Power, etc.);

"emergency condition" means the period of time when:

(a) the electric generation output of a facility with a malfunctioning air pollution control system cannot be reduced or electrical output must be increased because:

(i) all available system capacity of the company interconnected with the facility is being operated, and

(ii) all available purchase power interconnected with the facility is being obtained, or

(b) the electric generation demand is being shifted as quickly as possible from a facility with a malfunctioning air pollution control system to one or more electrical generating units held in reserve by the company or by a neighbouring company, or

(c) a facility with a malfunctioning air pollution control system becomes the only available unit to maintain a part or all of the company's system emergency reserves;

"facility" means that part of a steam generating plant for which these guidelines apply;

"fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat;

"malfunction" means partial or complete breakdown of equipment due to factors beyond the control of the operator;

"net system capacity" means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases, that are interconnected to the

"potential combustion concentration" means the theoretical emissions (ng/J, lb/million BTU heat input) that would result from combustion of a fuel in an uncleaned state (without emission control systems);

"reference method" means a method of sampling and analyzing for an air contaminant which is described in SSC-1/76;

"short term average" means for each contaminant, the average emissions determined from three tests completed in accordance with the "Stack Sampling Code, SSC-1/76";

"steam generating unit" means any furnace, boiler or other device used for combusting fuel for the purpose of producting steam (including fossil fuel fired steam generators associated with combined cycle gas turbines: nuclear steam generators are not included);

"solid-derived fuel" means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and synthetic crude from tar sands;

"720 hour rolling average" means for each contaminant, the average of the consecutive hourly mean emission rates, determined for the preceding 720 hours of system operation. Intervals of zero emissions are not to be included in the calculation of rolling averages;

"24 hour period" means the period of time between 12:00 a.m. and 12:00 midnight;

"AMD-77-1" means the document issued by the Pollution Control Division of the Department of the Environment entitled "Power Generating Industry Air Monitoring Directive";

"AMD-79-3" means the document issued by the Pollution Control Division of the Department of the Environment entitled "Source Emission Survey Report Format, Air Monitoring Directive";

"SSC-1/76" means the document entitled "Stack Sampling Code" issued by the Standards and Approvals Division of the Department of the Environment;

"VEE-2/77" means the document issued by the Standards and Approvals Division of the Department of the Environment entitled "Visible Emissions".

All other terms not defined herein have the same meaning that they have in the Clean Air Act and the Clean Air (Maximum Levels) Regulations.

Emission Limits

Particulate Matter

4.0 After the date on which the initial performance test required to be conducted under section 5 is completed, no owner or operator subject to the provisions of these guidelines, should discharge into the atmosphere from any steam generating unit an effluent stream which:

(a) contains particulate matter in excess of 43 nanograms per joule (0.1 pounds per million British Thermal Units) of heat input derived from the combustion of solid, liquid or gaseous fuel, based on a short term averaging period, and

(b) exhibits visible emissions greater than 20 percent opacity, except for one six minute period per hour of not more than 40 percent opacity.

Nitrogen Oxides (NO_x) expressed as Nitrogen Dioxide (NO_2)

4.1 After the date on which the initial performance test required to be conducted under section 5 is completed, no owner or operator subject to the provisions of these guidelines, should discharge into the atmosphere from any steam generating unit an effluent stream which contains nitrogen oxides in excess of the following emission limits:

(a) NO_x based on a 720 hour rolling averaging period and the specified fuel type,

Fuel Type	NO_x Emission Limit ng/J (lb/million BTU) Heat Input	
Gaseous Fuels:		
All gaseous fuels	86	(0.20)
Liquid Fuels:		
Solid derived fuels	210	(0.50)
Heavy oil (tar sands or in-situ bitumen derived)	210	(0.50)
All other fuels	129	(0.30)
Solid Fuels	258	(0.60)

(b) NO_x emission limits based on a short term averaging period for manual stack surveys should be the same limits as specified in clause 4.1(a),

(c) When two or more fuels are combusted simultaneously, the applicable limit is determined by proration using the following formula:

$$ENO_x = [86\,W + 129\,X + 210Y + 258Z]/100$$

where

ENO_x is the applicable limit for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input)

W is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input limits,

X is the percentage of total heat input derived from the combustion of fuels subject to the 129 ng/J input limit,

Y is the percentage of total heat input derived from the combustion of fuels subject to 210 ng/J heat input limit, and

Z is the percentage of total heat input derived from the combustion of fuels subject to 258 ng/J heat input limit.

Sulphur Dioxide (SO_2)

4.2 After the date on which the initial performance test required to be conducted under section 5 is completed, no owner or operator subject to the provisions of these guidelines, should discharge into the atmosphere from any steam generating unit an effluent stream which contains sulphur dioxide in excess of the following emission limits:

(a) SO_2 based on a 720 hour rolling averaging period and the specified fuel type,

Fuel Type	SO_2 Emission Limit ng/J (lb/million BTU) Heat Input	
All fuels with potential combustion concentration of SO_2 not exceeding 2580 ng/J (6 lb/million BTU) of heat input	258	(0.60)
All fuels with potential combustion concentration of SO_2 exceeding 2580 ng/J (6 lb/million BTU) of heat input	10 percent of the potential combustion of SO_2 but not exceeding 516 (1.20)	

(b) SO_2 based on a short term averaging period should be

(i) established on a site-specific basis for each plant before application is made for a Clean Air Act Licence to Operate or Use and

(ii) determined in practice to have a stringency equal to, but no greater than the limit specified in clause 4.2(a).

Source Performance Testing

5.0 Within 60 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after initial startup of such a facility and at such other times as may be required by the Department, the owner or operator of such a facility should conduct source performance test(s) and furnish the Department a written report of the results of such performance test(s).

5.1 Source performance tests should be conducted and data reduced in accordance with the test methods and procedures contained in sections 7 and 8 unless the Department

(a) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology,

(b) approves the use of an alternate method, or

(c) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Department's satisfaction that the facility is in compliance with the emission limit.

5.2 Under special circumstances an extention to the time period specified in subsection 5.0 may be allowed by the Department upon receipt of such a request made by the owner or operator of the facility.

5.3 The owner or operator of the facility should provide the Department at least 30 days prior notice of any source performance test, to afford the Department the opportunity to have an observer present.

Monitoring Requirements (Source/Ambient)

6.0 The owner or operator of a facility should install, calibrate, maintain, and operate continuous source emission monitoring systems, and record the output of the systems, for measuring:

(a) the opacity of the effluent stream emitted to the atmosphere except where gaseous fuel is the only fuel combusted,

(b) the temperature of the effluent stream,

(c) the concentration of nitrogen oxides expressed as NO_2, in the effluent stream, and

(d) the concentration of sulphur dioxide in the effluent stream, except where natural gas is the only fuel combusted, as follows:

(i) the sulphur dioxide concentration is monitored as discharged to the atmosphere, when no minimum percent removal is required; and
(ii) the sulphur dioxide concentrations are monitored at both the inlet and outlet of the sulphur dioxide control device, when a minimum of 90 percent removal is required; and

(e) the concentration of oxygen or carbon dioxide in the effluent stream.

6.1 The continuous source emission monitoring systems specified under subsection 6.0 should be operated and data recorded during all periods of operation of the facility, including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

6.2 When emission data are not obtained because of continuous source emission monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, other monitoring systems including calculation methods as approved by the Department or the reference methods should be used to provide emissions data for a minimum of 18 out of 24 hours in at least 22 out of 30 successive boiler operating days.

6.3 The hourly averages required under subsections 7.4 and 7.5 are expressed in ng/J (lbs/million BTU) heat input and used to calculate the 720 hour rolling average.

6.4 Subject to subsection 6.2, the 1-hour averages are calculated using at least

(a) two data points from the continuous monitoring system, or

(b) one test run from the manual stack survey test.

6.5 Reference methods of Appendix A should be used during each source performance test and emissions should be expressed in ng/J (lb/million BTU) heat input.

6.6 The frequency of source performance tests (manual stack surveys) will be specified by the Department in each plant's Licence to Operate or Use.

6.7 The following procedures are used to conduct an initial performance evaluation of continuous source emission monitoring system:

(a) Reference method 5 or 6, as applicable, is used for conducting performance evaluations of the sulphur dioxide and nitrogen oxides continuous source emission monitoring systems,

(b) Sulphur dioxide or nitrogen oxides, as applicable, is used for preparing calibration gas mixtures as specified in Table 3 in Appendix B under Step 1 of section 2.3,

(c) For facilities burning only fossil fuel, the span values for a continuous source emission monitoring system to measure opacity is between 60 and 80 percent and for a continuous source emission monitoring system measuring gaseous contaminant is determined as per Table 4 in Appendix B.

6.8 All continuous source emission monitoring systems should be in accordance with the applicable performance specifications as given in Appendix B.

6.9 For liquid and solid fossil fuels, the ultimate analysis and gross calorific value of the fuel should be determined and SO_2 emissions calculated by using Method No. (IX) of Appendix A or an equivalent method approved by the Department, once per boiler operating week unless specified otherwise in the Licence to Operate or Use.

6.10 For liquid and solid fossil fuels, sulphur content and gross calorific value of the fuel should be determined once per boiler operating day when

(a) the SO_2 continuous source emission monitor breaks down for a period in excess of 24 consecutive hours, or

(b) a manual source emission survey for SO_2, is conducted, or

(c) a minimum of 90% SO_2 removal is required.

6.11 To satisfy the ambient air quality objectives

(a) each thermal power generating plant should be designed such that the release of contaminants to the atmosphere does not result in concentrations in excess of those specified in the Clean Air (Maximum Levels) Regulations,

(b) each stack should be designed for the worst possible case with respect to emissions and other parameters as outlined in the Department of the Environment document entitled "Guidelines for Plume Dispersion Calculations", and

(c) all ambient air quality monitoring as specified in each plant's Licence to Operate or Use, should be carried out in accordance with AMD-77-1.

Compliance Provisions

7.0 All emission limits as specified in section 4, except the opacity, apply at all times except during periods of startup, shutdown or malfunction.

7.1 During emergency conditions, the facility with a malfunctioning air pollution control system may be operated if emissions are minimized by:

(a) operating all operable air pollution control system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed, and

(b) bypassing flue gases around only those air polluition control system modules that have been taken out of operation because they are incapable of any emission reduction or which would have suffered significant physical damage if they had remained in operation.

7.2 Data from the continuous opacity monitoring system should be used to assess performance of the particulate matter control system but not for compliance with the limit specified in subsection 4.0(b).

7.3 Visible emissions observed per "VEE-2/77" should be used to determine compliance with the limit specified in subsection 4.0(b).

7.4 After the initial performance test required under section 5, compliance with the sulphur dioxide emission limitations and the nitrogen oxides emission limitations under section 4, is based on the 720 hour rolling average. At the end of each boiler operating hour after the initial 720 hours of operation, a new 720 hour rolling average emission rate is calculated to show compliance with the emission limits.

7.5 Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 720 successive boiler operating hours, except for data obtained during startup, shutdown or malfunctions.

7.6 If an owner or operator has not obtained the minimum quantity of emission data as required under section 6, compliance of the affected facility with the emission requirements under section 4 should be determined by following the applicable procedures in Method No. (IX) of Appendix A.

7.7 Compliance with all emission limits based on a short term averaging period as specified in section 4 should be determined by using manual stack surveys only and should not be determined by using continuous source monitoring systems.

Compliance Determination Procedures and Methods

8.0 The following procedures and reference methods are used to determine compliance with the limit for particulate matter under section 4:

(a) Reference Method 4 of Appendix A is used for determining particulate matter emissions and associated moisture content;

(b) For determination of particulate emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Reference Method 4 by traversing the duct at the same sampling location;

(c) For each run using Reference Method 4, the emission rate expressed in ng/J heat input is determined using the oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section, the dry basis F factor and the dry basis emission rate calculation procedure contained in Method No. (IX) of Appendix A.

8.1 For fossil fuels with high potential combustion concentrations of sulphur dioxide as defined in clause 4.2(a), the following procedures and methods are used to determine compliance with the sulphur dioxide emission limit under section 4:

(a) Determine the percent of potential combustion concentration (percent PCC) emitted to the atmosphere as follows:

(i) Fuel Pretreatment ($\%R_f$): Determine the percentreduction achieved by any fuel pretreatment using the procedures in Method No.(IX) of Appendix A. Calculate the average percent reduction for fuel pretreatment on a monthly basis using fuel analysis data. The determination of $\% R_f$, to calculate the percent of potential combustion concentration emitted to the atmosphere is optional. For purposes of determining compliance with any percent reduction requirements under subsection 4.2 any reduction in potential SO_2 emissions resulting from the following processes may be credited:

(A) fuel pretreatment (physical or chemical coal cleaning, hydrodesulphurization of fuel oil, etc.),

(B) coal pulverizers if equipped with magnetic separators, and

(C) bottom and flyash interactions

(ii) Sulphur Dioxide Control System ($\%R_g$): Determine the percent sulphur dioxide reduction achieved by any sulphur dioxide control system using emission rates measured before and after the control system. When the "as fired" fuel monitor is used, the percent reduction is calculated using the average emission rate from the sulphur dioxide control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(iii) Overall Percent Reduction ($\%R_o$): Determine the overall percent reduction using the results obtained in (i) and (ii) of this subsection following the procedures in Method No. (IX) of Appendix A. Results are calculated for each 30 day period.

(iv) Percent Emitted (%PCC): Calculate the percent of potential combustion concentration emitted to the atmosphere using the following equation: Percent PCC = 100 - Percent R_o.

(v) Determine the sulphur dioxide emission rates following the procedures in Method No. (IX) of Appendix A.

8.2 The procedures and methods outlined in Method No. (IX) of Appendix A are used in conjunction with the 30 day nitrogen oxides emission data collected under section 6 to determine compliance with the applicable nitrogen oxides limits.

8.3 For electric utility combined cycle gas turbines, applicability of the emission limits is determined on the basis of the fossil fuel fired to the steam generator, not including the heat input and electrical power contribution of the gas turbine.

8.4 During all manual stack sampling tests, each steam generating unit should be operated at a minimum of 80 percent of the maximum designed capacity.

Reporting Requirements

9.0 For sulphur dioxide, nitrogen oxides and particulate matter emissions, the data from the source performance tests, continuous monitors including the transmissometer, and all ambient monitoring systems should be submitted to the Department in accordance with "AMD-77-1" and these guidelines on a monthly basis.

9.1 For sulphur dioxide and nitrogen oxides the following information should be reported to the Department for each 24 hour period;

(a) Calendar date,

(b) The average sulphur dioxide and nitrogen oxides emission rates (ng/J or lb/million BTU) based on 720 hour rolling averages for each 30 successive boiler operating days, reasons for non compliance with the emission limits and description of corrective actions taken,

(c) Percent reduction of the potential combustion concentration of sulphur dioxide for each 30 successive boiler operating days, (only when percent reduction specified in the licence)

(d) Identification of the boiler operating days for which contaminant (NO_x/SO_2) or diluent (CO_2/O_2) data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken,

(e) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only) or other reasons and justification for excluding data.

(f) Identification of "F" factor (defined in Section 5.2 of Method No. (IX) of Appendix A) used for calculations, method of determination and type of fuel combusted,

(g) Identification of times when hourly averages have been obtained based on manual sampling methods or other approved methods,

(h) Identification of the times when the contaminant concentration exceeded full span of the continuous monitoring system,

(i) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications of Appendix B.

9.2 If the minimum quantity of emission data as required by section 6 is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of subsection 7.6 should be reported to the Department for that 30 day period:

(a) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable,

(b) The standard deviation of hourly averages for outlet emission rates (S_o) and inlet emission rates (S_i) as applicable,

(c) The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable,

(d) The applicable potential combustion concentration,

(e) The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate(E_{std})as applicable.

9.3 If any limits under subsection 4.2 are exceeded during emergency conditions because of control system malfunction, the owner or operator of the facility should submit a signed statement:

(a) Indicating what emergency conditions existed and what requirements under subsection 7.1 were met during each period, and

(b) Listing the following information:

(i) times when the emergency condition existed;

(ii) electrical output and demand on the electric utility system and the affected facility;

(iii) amount of power purchased from interconnected neighbouring utility companies during the emergency period;

(iv) if applicable percent reduction achieved;

(v) atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) actions taken to correct control system malfunction.

9.4 If fuel pretreatment credit toward the sulphur dioxide emission limit is claimed, the owner or operator of the facility should submit a signed statement:

(a) Indicating what percentage cleaning credit was taken for the calendar month and whether the credit was determined in accordance with the provisions of section 8 and Method No. (IX) of Appendix A, and

(b) Listing the quantity, heat content, and date when each pretreated fuel shipment was received during the previous month, the name and location of the fuel pretreatment facility, and the total quantity and total heat content of all fuels received at the facility during the previous month.

9.5 For any periods for which opacity, sulphur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the facility shall submit a signed statement indicating whether any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and facility during periods when data is not available are to be compared with operation of the control system and facility before and following these periods.

9.6 The owner or operator of the facility should submit a signed statement indicating whether:

(a) The required continuous source emission monitoring system calibration, span and drift checks or other periodic audits have or have not been performed as specified,

(b) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of these guidelines and "AMD-77-1",

(c) The minimum data requirements have or have not been met, or the minimum data requirements have not been met for errors that were unavoidable,

(d) Compliance with the emission limits has or has not been achieved during the reporting period.

9.7 Subject to subsection 1.5 and for the purpose of the reports required under subsection 9.0, periods of excess visible emissions are defined as all 6 minute periods during which the average opacity as measured by the continuous source emission monitoring system exceeds the applicable opacity limit under subsection 4.0(b). Opacity levels in excess of the applicable opacity limit and the date of such excesses are to be submitted to the Department each month.

9.8 Source survey information collected in accordance with the requirements of subsection 5.0 should be tabulated and summarized in the form of a report in accordance with

(i) "AMD-79-3", and
(ii) Section 5 of the Method No. (IX) of Appendix A;

and forward to the Director of Pollution Control by the end of the month following the month in which the measurements were made.

10. APPENDICES

APPENDIX A

Method No.	Test Method Name	Reference Method
(i)	Sampling facilities and location of velocity traverses	"SSC-1/76" Method 1
(ii)	Determining stack gas velocity and volumetric flowrate	"SSC-1/76" Method 1
(iii)	Determination of gas composition and Mol. Wt. (CO_2, O_2, excess air and dry Mol. Wt.)	"SSC-1/76" Method 2
(iv)	Determination of moisture content in stack gases	"SSC-1/76" Method 3
(v)	Determination of particulate matter emissions	"SSC-1/76" Method 4
(vi)	Determination of sulphuric acid mist and sulphur dioxide emissions	"SSC-1/76" Method 5
(vii)	Determination of oxides of nitrogen emissions	"SSC-1/76" Method 6
(viii)	Visual determination of the opacity	"VEE-2/77"
(ix)	Determination of SO_2 removal efficiency and particulate, SO_2 and NO_x emission rates from steam generators	Appendix A (Page A.2)

METHOD NO. (ix)

Determination of SO_2 removal efficiency and particulate, sulphur dioxide and nitrogen oxides emission rates from electric utility steam generators.

METHOD—IX DETERMINATION OF SULFUR DIOXIDE REMOVAL EFFICIENCY AND PARTICULATE, SULFUR DIOXIDE AND NITROGEN OXIDES EMISSION RATES FROM ELECTRIC UTILITY STEAM GENERATORS

1. Principle and applicability

1.1 *Principle.*

1.1.1 Fuel samples from before and after fuel pretreatment systems are collected and analyzed for sulfur and heat content, and the percent sulfur dioxide (ng/Joule, lb/million Btu) reduction is calculated on a dry basis. (Optional Procedure.)

1.1.2 Sulfur dioxide and oxygen or carbon dioxide concentration data obtained from sampling emissions upstream and downstream of sulfur dioxide control devices are used to calculate sulfur dioxide removal efficiencies. (Minimum Requirement.) As an alternative to sulfur dioxide monitoring upstream of sulfur dioxide control devices, fuel samples may be collected in an as-fired condition and analyzed for sulfur and heat content. (Optional Procedure.)

1.1.3 An overall sulfur dioxide emission reduction efficiency is calculated from the efficiency of fuel pretreatment systems and the efficiency of sulfur dioxide control devices.

1.1.4 Particulate, sulfur dioxide, nitrogen oxides, and oxygen or carbon dioxide concentration data obtained from sampling emissions downstream from sulfur dioxide control devices are used along with F factors to calculate particulate, sulfur dioxide, and nitrogen oxides emission rates. F factors are values relating combustion gas volume to the heat content of fuels.

1.2 *Applicability.* This method is applicable for determining sulfur removal efficiencies of fuel pretreatment and sulfur dioxide control devices and the overall reduction of potential sulfur dioxide emissions from electric utility steam generators. This method is also applicable for the determination of particulate, sulfur dioxide, and nitrogen oxides emission rates.

2. Determination of Sulfur Dioxide Removal Efficiency of Fuel Pretreatment Systems

2.1 *Solid Fossil Fuel.*

2.1.1 *Sample Increment Collection.* Use ASTM D 2234[1], Type I, conditions A, B, or C, and systematic spacing. Determine the number and weight of increments required per gross sample representing each coal lot according to Table 2 or Paragraph 7.1.5.2 of ASTM D 2234[1]. Collect one gross sample for

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[1] Use the most recent revision or designation of the ASTM procedure specified.

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each raw coal lot and one gross sample for each product coal lot.

2.1.2 *ASTM Lot Size.* For the purpose of Section 2.1.1, the product coal lot size is defined as the weight of product coal produced from one type of raw coal. The raw coal lot size is the weight of raw coal used to produce one product coal lot. Typically, the lot size is the weight of coal processsed in a 1-day (24 hours) period. If more than one type of coal is treated and produced in 1 day, then gross samples must be collected and analyzed for each type of coal. A coal lot size equaling the 90-day quarterly fuel quantity for a specific power plant may be used if representative sampling can be conducted for the raw coal and product coal.

NOTE: Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

2.1.3 *Gross Sample Analysis.* Determine the percent sulfur content (%S) and gross calorific value (GCV) of the solid fuel on a dry basis for each gross sample. Use ASTM 2013[1] for sample preparation, ASTM D 3177[1] for sulfur analysis, and ASTM D 3173[1] for moisture analysis. Use ASTM D 3176[1] for gross calorific value determination.

2.2 *Liquid Fossil Fuel.*

2.2.1 *Sample Collection.* Use ASTM D 270[1] following the practices outlined for continuous sampling for each gross sample representing each fuel lot.

2.2.2 *Lot Size.* For the purposes of Section 2.2.1, the weight of product fuel from one pretreatment facility and intended as one shipment (ship load, barge load, etc.) is defined as one product fuel lot. The weight of each crude liquid fuel type used to produce one product fuel lot is defined as one inlet fuel lot.

NOTE: Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

NOTE: For the purposes of this method, raw or inlet fuel (coal or oil) is defined as the fuel delivered to the desulfurization pretreatment facility or to the steam generating plant. For pretreated oil the input oil to the oil desulfurization process (e.g. hydrotreatment emitted) is sampled.

2.2.3 *Sample Analysis.* Determine the percent sulfur content (%S) and gross calorific value (GCV). Use ASTMD 240[1] for the sample analysis. This value can be assumed to be on a dry basis.

2.3 *Calculation of Sulfur Dioxide Removal Efficiency Due to Fuel Pretreatment.* Calculate the percent sulfur dioxide reduction due to fuel pretreatment using the following equation:

$$\%R_f = 100 \left[1 - \frac{\%S_o/GCV_o}{\%S_i/GCV_i} \right]$$

Where:

$\%R_f$=Sulfur dioxide removal efficiency due pretreatment; percent.

$\%S_o$=Sulfur content of the product fuel lot on a dry basis; weight percent.

$\%S_i$=Sulfur content of the inlet fuel lot on a dry basis; weight percent.

GCV_o=Gross calorific value for the outlet fuel lot on a dry basis; kJ/kg (Btu/lb).

GCV_i=Gross calorific value for the inlet fuel lot on a dry basis; kJ/kg (Btu/lb).

NOTE: If more than one fuel type is used to produce the product fuel, use the following equation to calculate the sulfur contents per unit of heat content of the total fuel lot, %S/GCV:

$$\%S/GCV = \sum_{k=1}^{n} Y_k(\%S_k/GCV_k)$$

Where:

Y_k=The fraction of total mass input derived from each type, k, of fuel.

$\%S_k$=Sulfur content of each fuel type, k, on a dry basis; weight percent.

GCV_k=Gross calorific value for each fuel type, k, on a dry basis; kJ/kg (Btu/lb).

n=The number of different types of fuels.

3. Determination of Sulfur Removal Efficiency of the Sulfur Dioxide Control Device

3.1 *Sampling.* Determine SO_2 emission rates at the inlet and outlet of the sulfur dioxide control system according to methods specified in the applicable subpart of the regulations and the procedures specified in Section 5. The inlet sulfur dioxide emission rate may be determined through fuel analysis (Optional, see Section 3.3.)

3.2. *Calculation.* Calculate the percent removal efficiency using the following equation:

$$\%R_{g(m)} = 100 \times (1.0 - \frac{E_{SO_2 o}}{E_{SO_2 i}})$$

Where:

$\%R_g$ =Sulfur dioxide removal efficiency of the sulfur dioxide control system using inlet and outlet monitoring data; percent.

$E_{SO_2 o}$=Sulfur dioxide emission rate from the outlet of the sulfur dioxide control system; ng/J (lb/million Btu).

$E_{SO_2 i}$=Sulfur dioxide emission rate to the outlet of the sulfur dioxide control system; ng/J (lb/million Btu).

3.3 *As-fired Fuel Analysis (Optional Procedure).* If the owner or operator of an electric utility steam generator chooses to determine the sulfur dioxide imput rate at the inlet to the sulfur dioxide control device through an as-fired fuel analysis in lieu of data from a sulfur dioxide control system inlet gas monitor, fuel samples must be collected in accordance with applicable paragraph in Section 2. The sampling can be conducted upstream of any fuel processing, e.g., plant coal pulverization. For the purposes of this section, a fuel lot size is defined as the weight of fuel consumed in 1 day (24 hours) and is directly related to the exhaust gas monitoring data at the outlet of the sulfur dioxide control system.

3.3.1 *Fuel Analysis.* Fuel samples must be analyzed for sulfur content and gross calorific value. The ASTM procedures for determining sulfur content are defined in the applicable paragraphs of Section 2.

3.3.2 *Calculation of Sulfur Dioxide Input Rate.* The sulfur dioxide imput rate determined from fuel analysis is calculated by:

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^7 \quad \text{for S. I. units.}$$

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^4 \quad \text{for English units.}$$

Where:

I_s = Sulfur dioxide input rate from as-fired fuel analysis, ng/J (lb/million Btu).

$\%S_f$ = Sulfur content of as-fired fuel, on a dry basis; weight percent.

GCV = Gross calorific value for as-fired fuel, on a dry basis; kJ/kg (Btu/lb).

3.3.3 *Calculation of Sulfur Dioxide Emission Reduction Using As-fired Fuel Analysis.* The sulfur dioxide emission reduction efficiency is calculated using the sulfur imput rate from paragraph 3.3.2 and the sulfur dioxide emission rate, E_{SO_2}, determined in the applicable paragraph of Section 5.3. The equation for sulfur dioxide emission reduction efficiency is:

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[1] Use the most recent revision or designation of the ASTM procedure specified.

Where:

$\%R_{g(f)}$ = Sulfur dioxide removal efficiency of the sulfur dioxide control system using as-fired fuel analysis data; percent.

E_{SO_2} = Sulfur dioxide emission rate from sulfur dioxide control system; ng/J (lb/million Btu).

I_s = Sulfur dioxide input rate from as-fired fuel analysis; ng/J (lb/million Btu).

4. Calculation of Overall Reduction in Potential Sulfur Dioxide Emission

4.1 The overall percent sulfur dioxide reduction calculation uses the sulfur dioxide concentration at the inlet to the sulfur dioxide control device as the base value. Any sulfur reduction realized through fuel cleaning is introduced into the equation as an average percent reduction, $\%R_f$.

4.2 Calculate the overall percent sulfur reduction as:

A.4

$$\%R_o = 100\left[1.0 - \left(1.0 - \frac{\%R_f}{100}\right)\left(1.0 - \frac{\%R_g}{100}\right)\right]$$

Where:

$\%R_o$ = Overall sulfur dioxide reduction; percent.

$\%R_f$ = Sulfur dioxide removal efficiency of fuel pretreatment from Section 2; percent. Refer to applicable subpart for definition of applicable averaging period.

$\%R_g$ = Sulfur dioxide removal efficiency of sulfur dioxide control device either O_2 or CO_2 - based calculation or calculated from fuel analysis and emission data, from Section 3; percent. Refer to applicable subpart for definition of applicable averaging period.

5. Calculation of Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates

5.1 *Sampling.* Use the outlet SO_2 or O_2 or CO_2 concentrations data obtained in Section 3.1. Determine the particulate, NO_x, and O_2 or CO_2 concentrations according to methods specified in an applicable subpart of the regulations.

5.2 *Determination of an F Factor.* Select an average F factor (Section 5.2.1) or calculate an applicable F factor (Section 5.2.2.). If combined fuels are fired, the selected or calculated F factors are prorated using the procedures in Section 5.2.3. F factors are ratios of the gas volume released during combustion of a fuel divided by the heat content of the fuel. A dry F factor (F_d) is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted; a wet F factor (F_w) is the ratio of the volume of wet flue gases generated to the calorific value of the fuel combusted; and the carbon F factor (F_c) is the ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted. When pollutant and oxygen concentrations have been determined in Section 5.1, wet or dry F factors are used. (F_w) factors and associated emission calculation procedures are not applicable and may not be used after wet scrubbers; (F_c) or (F_d) factors and associated emission calculation procedures are used after wet scrubbers.) When pollutant and carbon dioxide concentrations have been determined in Section 5.1, F_c factors are used.

5.2.1 *Average F Factors.* Table 1 shows average F_d, F_w, and F_c factors (scm/J, scf/million Btu) determined for commonly used fuels. For fuels not listed in Table 1, the F factors are calculated according to the procedures outlined in Section 5.2.2 of this section.

5.2.2 *Calculating an F Factor.* If the fuel burned is not listed in Table 1 or if the owner or operator chooses to determine an F factor rather than use the tabulated data, F factors are calculated using the equations below. The sampling and analysis procedures followed in obtaining data for these calculations are subject to the approval of the Administrator and the Administrator should be consulted prior to data collection.

For SI Units:

$$F_d = \frac{227.0(\%H) + 95.7(\%C) + 35.4(\%S) + 8.6(\%N) - 28.5(\%O)}{GCV}$$

$$F_w = \frac{347.4(\%H)+95.7(\%C)+35.4(\%S)+8.6(\%N)-28.5(\%O)+13.0(\%H_2O)^{**}}{GCV_w}$$

$$F_c = \frac{20.0(\%C)}{GCV}$$

For English Units:

$$F_d = \frac{10^6[5.57(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{GCV}$$

$$F_w = \frac{10^6[5.57(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)+0.21(\%H_2O)^{**}]}{GCV_w}$$

$$F_c = \frac{10^6[0.321(\%C)]}{GCV}$$

** The $\%H_2O$ term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.

Where:

F_d, F_w, and F_c have the units of scm/J, or scf/million Btu; %H, %C, %S, %N, %O, and $\%H_2O$ are the concentrations by weight (expressed in percent) of hydrogen, carbon, sulfur, nitrogen, oxygen, and water from an ultimate analysis of the fuel; and GCV is the gross calorific value of the fuel in kJ/kg or Btu/lb and consistent with the ultimate analysis. Follow ASTM D 2015° for solid fuels, D 240° for liquid fuels, and D 1826° for gaseous fuels as applicable in determining GCV.

5.2.3 *Combined Fuel Firing F Factor.* For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F_d, F_w, or F_c factors determined by Sections 5.2.1 or 5.2.2 of this section shall be prorated in accordance with applicable formula as follows:

$$F_d = \sum_{k=1}^{n} x_k F_{dk} \quad \text{or}$$

$$F_w = \sum_{k=1}^{n} x_k F_{wk} \quad \text{or}$$

$$F_c = \sum_{k=1}^{n} x_k F_{ck}$$

Where:

x_k=The fraction of total heat input derived from each type of fuel, K.

n=The number of fuels being burned in combination.

5.3 *Calculation of Emission Rate.* Select from the following paragraphs the applicable calculation procedure and calculate the particulate, SO_2, and NO_x emission rate. The values in the equations are defined as:

E=Pollutant emission rate, ng/J (lb/million Btu).

C=Pollutant concentration, ng/scm (lb/scf).

NOTE: It is necessary in some cases to convert measured concentration units to other units for these calculations.

Use the following table for such conversions:

CONVERSION FACTORS FOR CONCENTRATION

From—	To—	Multiply by—
g/scm	ng/scm	10^9.
mg/scm	ng/scm	10^6.
lb/scf	ng/scm	1.602×10^{13}.
ppm(SO_2)	ng/scm	2.660×10^6.
ppm(NO_2)	ng/scm	1.912×10^6.
ppm/(SO_2)	lb/scf	1.660×10^{-7}.
ppm/(NO_2)	lb/scf	1.194×10^{-7}.

5.3.1 *Oxygen-Based F Factor Procedure.*

5.3.1.1 *Dry Basis.* When both percent oxygen ($\%O_{2d}$) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_d \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

5.3.1.2 *Wet Basis.* When both the percent oxygen ($\%O_{2w}$) and the pollutant concentration (C_w) are measured in the flue gas on a wet basis, the following equations are applicable:

NOTE: F_w factors are not applicable after wet scrubbers.

$$\text{(a)} \quad E = C_w F_w \left[\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2w}}\right]$$

Where:

B_{wa}=Proportion by volume of water vapor in the ambient air.

In lieu of actual measurement, B_{wa} may be estimated as follows:

NOTE: The following estimating factors are selected to assure that any negative error introduced in the term:

$$\left(\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2ws}}\right)$$

will not be larger than −1.5 percent. However, positive errors, or over-estimation of emissions, of as much as 5 percent may be introduced depending upon the geographic location of the facility and the associated range of ambient moisture.

(i) B_{wa}=0.027. This factor may be used as a constant value at any location.

(ii) B_{wa}=Highest monthly average of B_{wa} which occurred within a calendar year at the nearest Weather Service Station.

(iii) B_{wa}=Highest daily average of B_{wa} which occurred within a calendar month at the nearest Weather Service Station, calculated from the data for the past 3 years. This factor shall be calculated for each month and may be used as an estimating factor for the respective calendar month.

$$\text{(b)} \quad E = C_w F_d \left[\frac{20.9}{20.9\,(1 - B_{ws}) - \%O_{2w}}\right]$$

Where:

B_{ws}=Proportion by volume of water vapor in the stack gas.

5.3.1.3 *Dry/Wet Basis.* When the pollutant concentration (C_w) is measured on a wet basis and the oxygen concentration ($\%O_{2d}$) or measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_d}{(1 - B_{ws})}\right] \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

When the pollutant concentration (C_d) is measured on a dry basis and the oxygen concentration ($\%O_{2w}$) is measured on a wet basis, the following equation is applicable:

$$E = C_d F_d \frac{20.9}{20.9 - \frac{\%O_{2w}}{(1 - B_{ws})}}$$

5.3.2 *Carbon Dioxide-Based F Factor Procedure.*

5.3.2.1 *Dry Basis.* When both the percent carbon dioxide ($\%CO_{2d}$) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_c \left(\frac{100}{\%CO_{2d}}\right)$$

5.3.2.2 *Wet Basis.* When both the percent carbon dioxide ($\%CO_{2w}$) and the pollutant concentration (C_w) are measured on a wet basis, the following equation is applicable:

$$E = C_w F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.3.2.3 *Dry/Wet Basis.* When the pollutant concentration (C_w) is measured on a wet basis and the percent carbon dioxide ($\%CO_{2d}$) is measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_c}{(1 - B_{ws})}\right] \left[\frac{100}{\%CO_{2d}}\right]$$

When the pollutant concentration (C_d) is measured on a dry basis and the precent carbon dioxide (%CO_{2w}) is measured on a wet basis, the following equation is applicable:

$$E = C_d (1 - B_{ws}) F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.4 *Calculation of Emission Rate from Combined Cycle-Gas Turbine Systems.* For gas turbine-steam generator combined cycle systems, the emissions from supplemental fuel fired to the steam generator or the percentage reduction in potential (SO_2) emissions cannot be determined directly. Using measurements from the gas turbine exhaust (performance test, subpart GG) and the combined exhaust gases from the steam generator, calculate the emission rates for these two points following the appropriate paragraphs in Section 5.3.

NOTE: F_w factors shall not be used to determine emission rates from gas turbines because of the injection of steam nor to calculate emission rates after wet scrubbers; F_d or F_c factor and associated calculation procedures are used to combine effluent emissions according to the procedure in Paragraph 5.2.3.

The emission rate from the steam generator is calculated as:

$$E_{sg} = \frac{E_c - X_{gt} E_{gt}}{X_{sg}}$$

Where:

E_{sg}=Pollutant emission rate from steam generator effluent, ng/J (lb/million Btu).

E_c=Pollutant emission rate in combined cycle effluent; ng/J (lb/million Btu).

E_{gt}=Pollutant emission rate from gas turbine effluent; ng/J (lb/million Btu).

X_{sg}=Fraction of total heat input from supplemental fuel fired to the steam generator.

X_{gt}=Fraction of total heat input from gas turbine exhaust gases.

NOTE: The total heat input to the steam generator is the sum of the heat input from supplemental fuel fired to the steam generator and the heat input to the steam generator from the exhaust gases from the gas turbine.

5.5 *Effect of Wet Scrubber Exhaust, Direct-Fired Reheat Fuel Burning.* Some wet scrubber systems require that the temperature of the exhaust gas be raised above the moisture dew-point prior to the gas entering the stack. One method used to accomplish this is directfiring of an auxiliary burner into the exhaust gas. The heat required for such burners is from 1 to 2 percent of total heat input of the steam generating plant. The effect of this fuel burning on the exhaust gas components will be less than ±1.0 percent and will have a similar effect on emission rate calculations. Because of this small effect, a determination of effluent gas constituents from direct-fired reheat burners for correction of stack gas concentrations is not necessary.

TABLE 19-1—F FACTORS FOR VARIOUS FUELS [1]

Fuel type	F_d		F_w		F_c	
	dscm J	dscf 10^6 Btu	wscm J	wscf J 10^6 Btu	scm J	scf 10^6 Btu
Coal:						
Anthracite [2]	2.71×10^{-7}	(10100)	2.83×10^{-7}	(10540)	0.530×10^{-7}	(1970)
Bituminous [2]	2.63×10^{-7}	(9780)	2.86×10^{-7}	(10640)	0.484×10^{-7}	(1800)
Lignite	2.65×10^{-7}	(9860)	3.21×10^{-7}	(11950)	0.513×10^{-7}	(1910)
Oil [3]	2.47×10^{-7}	(9190)	2.77×10^{-7}	(10320)	0.383×10^{-7}	(1420)
Gas:						
Natural	2.43×10^{-7}	(8710)	2.85×10^{-7}	(10610)	0.287×10^{-7}	(1040)
Propane	2.34×10^{-7}	(8710)	2.74×10^{-7}	(10200)	0.321×10^{-7}	(1190)
Butane	2.34×10^{-7}	(8710)	2.79×10^{-7}	(10390)	0.337×10^{-7}	(1250)
Wood	2.48×10^{-7}	(9240)			0.492×10^{-7}	(1830)
Wood Bark	2.58×10^{-7}	(9600)			0.497×10^{-7}	(1850)

[1] Determined at standard conditions: 20° C (68° F) and 760 mm Hg (29.92 in. Hg).
[2] As classified according to ASTM D 388–66.
[3] Crude, residual, or distillate.

6. *Calculation of Confidence Limits for Inlet and Outlet Monitoring Data*

6.1 *Mean Emission Rates.* Calculate the mean emission rates using hourly averages in ng/J (lb/million Btu) for SO_2 and NO_x outlet data and, if applicable, SO_2 inlet data using the following equations:

$$E_o = \frac{\Sigma x_o}{n_o}$$

$$E_i = \frac{\Sigma x_i}{n_i}$$

Where:

E_o=Mean outlet emission rate; ng/J (lb/million Btu).

E_i=Mean inlet emission rate; ng/J (lb/million Btu).

x_o=Hourly average outlet emission rate; ng/J (lb/million Btu).

x_i=Hourly average in let emission rate; ng/J (lb/million Btu).

n_o=Number of outlet hourly averages available for the reporting period.

n_i=Number of inlet hourly averages available for reporting period.

6.2 *Standard Deviation of Hourly Emission Rates.* Calculate the standard deviation of the available outlet hourly average emission rates for SO_2 and NO_x and, if applicable, the available inlet hourly average emission rates for SO_2 using the following equations:

$$s_o = \left(\sqrt{\frac{1}{n_o} - \frac{1}{720}}\right) \left(\sqrt{\frac{\Sigma (E_o - x_o)^2}{n_o - 1}}\right)$$

$$s_i = \left(\sqrt{\frac{1}{n_i} - \frac{1}{720}}\right) \left(\sqrt{\frac{\Sigma (E_i - x_i)^2}{n_i - 1}}\right)$$

Where:

s_o=Standard deviation of the average outlet hourly average emission rates for the reporting period; ng/J (lb/million Btu).

s_i=Standard deviation of the average inlet hourly average emission rates for the reporting period; ng/J (lb/million Btu).

6.3 *Confidence Limits.* Calculate the lower confidence limit for the mean outlet emission rates for SO_2 and NO_x and, if applicable, the upper confidence limit for the mean inlet emission rate for SO_2 using the following equations:

$E_o^* = E_o - t_{0.95} s_o$
$E_i^* = E_i + t_{0.95} s_i$

Where:

E_o^*=The lower confidence limit for the mean outlet emission rates; ng/J (lb/million Btu).

E_i^*=The upper confidence limit for the mean inlet emission rate; ng/J (lb/million Btu).

$t_{0.95}$=Values shown below for the indicated number of available data points (n):

VALUES FOR $T_{0.95}$

n	$t_{0.95}$
2	6.31
3	2.42
4	2.35
5	2.13
6	2.02
7	1.94
8	1.89
9	1.86
10	1.83
11	1.81
12-16	1.77
17-21	1.73
22-26	1.71
27-31	1.70
32-51	1.68
52-91	1.67
92-151	1.66
152 or more	1.65

The values of this table are corrected for n-1 degrees of freedom. Use n equal to the number of hourly average data points.

7. Calculation to Demonstrate Compliance When Available Monitoring Data Are Less Than the Required Minimum

7.1 *Determine Potential Combustion Concentration (PCC) for SO_2.*

7.1.1 When the removal efficiency due to fuel pretreatment (% R_f) is included in the overall reduction in potential sulfur dioxide emissions (% R_o) and the "as-fired" fuel analysis is not used, the potential combustion concentration (PCC) is determined as follows:

$$PCC = E_i^{*} + 2\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)10^7;\ ng/J$$

$$PCC = E_i^{*} + 2\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)10^4;\ lb/million\ Btu.$$

Where:

$\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)$ = Potential emissions removed by the pretreatment process, using the fuel parameters defined in section 2.3; ng/J (lb/million Btu).

7.1.2 When the "as-fired" fuel analysis is used and the removal efficiency due to fuel pretreatment (% R_f) is not included in the overall reduction in potential sulfur dioxide emissions (% R_o), the potential combustion concentration (PCC) is determined as follows:

$PCC = I_s$

Where:

I_s = The sulfur dioxide input rate as defined in section 3.3

7.1.3 When the "as-fired" fuel analysis is used and the removal efficiency due to fuel pretreatment (% R_f) is included in the overall reduction (% R_o), the potential combustion concentration (PCC) is determined as follows:

$$PCC = I_s + 2\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)10^7;\ ng/J$$

$$PCC = I_s + 2\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)10^4;\ lb/million\ Btu.$$

7.1.4 When inlet monitoring data are used and the removal efficiency due to fuel pretreatment (% R_f) is not included in the overall reduction in potential sulfur dioxide emissions (% R_o), the potential combustion concentration (PCC) is determined as follows:

$PCC = E_i^{\circ}$

Where:

E_i° = The upper confidence limit of the mean inlet emission rate, as determined in section 6.3.

7.2 *Determine Allowable Emission Rates (E_{std}).*

7.2.1 *NO_x.* Use the allowable emission rates for NO_x as directly defined by the applicable standard in terms of ng/J (lb/million Btu).

7.2.2 *SO_2.* Use the potential combustion concentration (PCC) for SO_2 as determined in section 7.1, to determine the applicable emission standard. If the applicable standard is an allowable emission rate in ng/J (lb/million Btu), the allowable emission rate is used as E_{std}. If the applicable standard is an allowable percent emission, calculate the allowable emission rate (E_{std}) using the following equation:

$E_{std} = \%\ PCC/100$

Where:

% PCC = Allowable percent emission as defined by the applicable standard; percent.

7.3 *Calculate E_o°/E_{std}.* To determine compliance for the reporting period calculate the ratio:

E_o°/E_{std}

Where:

E_o° = The lower confidence limit for the mean outlet emission rates, as defined in section 6.3; ng/J (lb/million Btu).

E_{std} = Allowable emission rate as defined in section 7.2; ng/J (lb/million Btu).

If E_o°/E_{std} is equal to or less than 1.0, the facility is in compliance; if E_o°/E_{std} is greater than 1.0, the facility is not in compliance for the reporting period.

APPENDIX B

PERFORMANCE SPECIFICATIONS FOR CONTINUOUS SOURCE EMISSION MONITORING SYSTEMS

CONTINUOUS MONITORS FOR OPACITY MEASUREMENTS

Opacity and Transmittance

1.0 The term "transmissometer" is a combination of "transmission" and "meter". Basically when light passes through a plume of flue, some of the light will be scattered and absorbed by particulate matter in the plume. The absorbed and scattered light will not reach the detector on the other side of the flue gas and will be lost to observation. The transmission of the light through the gas is, therefore, decreased. A transmissometer is essentially a meter that shows a quantitative value of the decrease in light transmission.

If light is not able to penetrate through a plume, the plume is said to be opaque - the opacity of the plume is 100 percent. Transmittance and opacity can be related in the following manner:

Percent Transmittance = 100 - Percent Opacity

Therefore, if a plume or object is 100 percent opaque, the transmittance of light through it is zero. If it is not opaque (zero percent opacity), the transmittance of light will be 100 percent. A plume from a stationary source rarely will have either zero or 100 percent opacity, but some intermediate value.

Opacity is a measure of the degree to which the emissions from a stack obscure the view of an object in the background. Opacity readings (in percentage) indicate the visibility-obscuring properties of the total gas stream, not the particulates alone. The opacity monitor does not provide a reading of particulate concentration ($\mu g/m^3$ or other units); most stack monitoring that does measure particulate concentration is still done by manual methods.

The Performance Specification Test

1.1 For the Performance Specification Test, the opacity monitors must undergo a one week conditioning period and a one week operational test period. In the conditioning period, the monitor is merely turned on and is run in a normal manner. This is essentially a burn-in period for the new instrument to eliminate the problems one might expect in a new device. In the operational test period, the monitor is run for one week without any corrective maintenance, repair or replacement of parts, other than as required by normal operating procedure. During this period, 24-hour zero and calibration drift characteristics are determined. If the instrument is poorly designed or if it is poorly mounted, these problems should become evident from the drift data, and corrective action would have to be taken. Only zero, calibration drift, and response time data are necessary for the performance test. The acceptable limits for these parameters are given in Table 1.

TABLE 1 PERFORMANCE SPECIFICATIONS FOR OPACITY MONITORS

Parameters	Specifications
Calibration error*	≤3 % opacity
Zero drift* (24 hours)	≤2% opacity
Calibration drift* (24 hours)	≤2% opacity
Response time	10 sec (maximum)

*Expressed as a sum of absolute mean value plus 95% confidence interval of a series of tests

Installation Specifications

1.2 After an approved transmissometer has been selected by the source operator, the instrument must be installed and checked for proper operation on the source itself. There are several points that must be considered when installing a transmissometer:

(a) It must be located across a section of duct or stack that will provide a representative measurement of the actual flue gas opacity.

(b) It must be downstream from the particulate control equipment and it should

(i) meet the location criteria specified in "SSC-1/76", or
(ii) be as far away as possible from bends and obstructions when the location criteria cannot be met.

(c) It must be installed in the plane of the bend if located in a duct or stack following a bend.

(d) It should be installed in an accessible location.

(e) It may be required to demonstrate that it is obtaining representative opacity values at its installed location.

These installation specifications are designed so that the transmissometer will measure the actual flue gas opacity of "an optical volume which is representative of the particulate matter flowing through the duct or stack".

1.3 Measuring and Recording Specifications

Opacity monitoring systems must be capable of measuring opacities at a minimum of once every 10 seconds. Average readings are to be recorded at least once every 6 minutes by an appropriate strip-chart recorder or data-logging device.

Once an opacity monitor is put into operation, a record of each consecutive 6-minute average, calculated manually or automatically, must be kept for reporting purposes. To assure proper operation, zero and span checks are made daily. Maintenance, cleaning, and optical alignment are performed as needed.

2.0 Sources required to install continuous-gaseous emission monitors should select instruments which will give data representing the actual source emissions.

The proper selection or evaluation of a gas analyzer requires knowledge of the practical differences between extractive and in-situ systems and knowledge of the operating principles of the analyzers themselves.

2.1 The general considerations for a continuous monitor of gaseous pollutants are listed in Table 2.

TABLE 2 CRITERIA FOR CONTINUOUS MONITORS FOR GASES

Specificity	Response should be only to trace material(s) of interest.
Sensitivity	Method must be sensitive over the concentration range of interest.
Stability	Sample must be stable in the analyzer.
Accuracy	Results must be reproducible, and must represent the actual stack concentration when compared with the reference method gases.
Sample average time	Method must fit into the required sample averaging time for control.
Feasibility	Instrument investment and maintenance costs, analysis time, and manpower must be consistent with needs and resources.
Calibration	Instrument should not drift; calibration and other corrections should be automatic.
Response	Instrument must function rapidly enough to record significant process changes as they occur.
Effect of ambient conditions	Changes in temperature and humidity must not affect the accuracy of the observed results.
Data output	For some applications, output of the analyzer should be in a machine-readable format.

2.2 The selection of a monitor is dependent upon the Performance Specification Test. A gaseous-emissions monitoring instrument must meet the following specifications:

TABLE 3 MONITOR PERFORMANCE SPECIFICATIONS

PARAMETER	SPECIFICATIONS OF	
	SO_2 & NO_x MONITOR	O_2 & CO_2 MONITOR
1 Response time	$\leq$ 15 minutes	$\leq$ 15 minutes
2 Zero drift	% of span value	% of O_2 or CO_2
(a) 2 hour	$\leq$ 2.5	$\leq$ 0.5
(b) 24 hour	$\leq$ 2.5	$\leq$ 0.5
3 Calibration drift	% of span value	% of O_2 or CO_2
(a) 2 hour	$\leq$ 2.5	$\leq$ 0.5
(b) 24 hour	$\leq$ 2.5	$\leq$ 0.5
4 Calibration error	$\leq$5% of span value	$\leq$ 0.5 of O_2 or CO_2
5 Relative accuracy(*)	$\leq$ 20% or 10% of emission limit whichever is greater	-
6 Accuracy(**)	-	$\leq$1% of O_2 or CO_2
7 Operational period	168 hours minimum	168 hours minimum

* Expressed as the sum of the absolute mean of the difference plus the 2.5% error confidence coefficient of a series of tests divided by a reference value (mean value obtained through manual stack surveys)

** Expressed as the sum of the absolute mean of the differences plus the 2.5% error confidence coefficient of a series of tests

The Performance Specification Tests and Certification Procedures

2.3 Certification of the continuous monitor's accuracy must be completed in the seven steps outlined below:

Step 1. Analysis of Calibration Gases. The monitoring instrument must be calibrated at three concentrations of the contaminant in question: 0, 50 and 90 percent of span. Each calibration gas must be analyzed three times.

Step 2. Calibration Check. The three calibration gases must be analyzed by the monitor for a total of 15 readings. This step can be completed prior to the 168-hour operational period.

Step 3. Zero Drift Check. The zero must be offset by at least 10 percent of the span to check negative zero drift.

Step 4. Operational Test. After installation the monitor must be operated for an additional period to verify proper operation.

Step 5. Relative Accuracy Test. Gas samples are extracted from the stack and analyzed for the contaminant in question by the manual reference method. At least twelve samples must be collected with the option to reject up to three sets of test results. Compare the analytical results with the monitor averages for the corresponding sampling period.

Step 6. Field Calibration Check. The zero and span drifts must be checked for a minimum of 15 two-hour periods. This check can be simultaneous with the accuracy test.

Step 7. Response Time Check. When the monitor is in place, the response time of the instrument from a zero reading to maximum concentration is measured at least three times.

2.4 Planning, Coordinating and Executing Performance Tests

A careful planning and coordination in advance of the required testing period is essential to avoid unnecessary expense and delay. To complete successfully an instrument performance evaluation, one must:

(a) review the guidelines to determine applicability and specific test requirements,

(b) review test procedures and documentation requirements with the Department and instrument suppliers,

(c) establish a test schedule and assign testing, documentation, and coordination responsibilities,

(d) notify the Department for witnessing requirements,

(e) perform all tests that are allowed to be conducted prior to the 168-hour test periods if not performed by vendor prior to shipment (calibration error for all and response time for opacity monitor only),

(f) confirm proper instrument operation and adequate expendables supply for test periods,

(g) perform and monitor the required tests during the 168-hour period,

(h) reduce the data and generate a test report complying with the requirements of the guidelines or permit or licence.

2.5 Exceptions Under Special Circumstances

(a) for special continuous monitors, the performance specifications and certification procedures may be modified with the approval of the Department;

(b) NO_x/SO_2 monitors may be exempted from the relative accuracy test requirements by the Department if manual stack tests indicate emissions less than 70% of the limit based on 720-rolling hour average.

Span and Calibration Gas Values

2.6 A listing of calibration gas concentrations for a fossil-fuel steam generating facility is shown in Table 4.

TABLE 4 SPAN AND CALIBRATION GAS VALUES

Gas Monitored	Type of Fossil Fuel	Span Value	Calibration Gas Value 50% of Span Value	90% of Span Value
SO_2	Liquid Solid	1000 ppm 1500	500 ppm 750	900 ppm 1350
NO_x	Gas Liquid Solid	500 ppm 500 1000	250 ppm 250 500	450 ppm 450 900
O_2	-	1.5 to 2.5 times normal source concentration	0.50 Span Value	0.90 Span Value or Ambient if span>21%
CO_2	-	1.5 to 2.5 times normal source concentration	0.50 Span Value	0.90 Span Value

Measuring and Recording Requirements for Continuous Monitors

2.7 The minimum requirements for each monitor are specified in Table 5 and 6.

TABLE 5 MEASURING REQUIREMENTS

Opacity	- Completion of one cycle of operation (sampling and analysis) every 10 seconds
SO_2, NO_x CO_2, O_2	- Completion of one cycle of operation (sampling and analysis) every 10 minutes

TABLE 6 RECORDING REQUIREMENTS

Opacity	- An average of at least 24 equally spaced data points taken over a 6-minute period is to be recorded every 6 minutes.
SO_2, NO_x, CO_2, O_2	- An average of at least 4 equally spaced data points taken over an hour is to be recorded every hour. - Hourly averages are based on clock hours.

Monitor Location and Installation

2.8 A continuous gas monitor must be located at a sampling point where measurements are directly representative or can be corrected to be representative of the total emissions. The requirements for the location and installation of extractive and in-situ type monitors at a source are:

(a) Stack gases may be assumed to be nonstratified at any point greater than 8 duct diameters downstream of air in-leakage.

(b) The assumption on stratification may not be made for sampling locations upstream of an air preheater at a steam-generating facility.

(c) For sampling points located where the gas is assumed or demonstrated to be nonstratified, extractive or in-situ monitors may sample at a point of average concentration.

(d) Extractive sampling points must not be closer than 1 meter to the stack wall.

(e) Multipoint extractive sampling probes may be located at any points necessary to obtain consistently representative gas samples.

(f) Sampling locations at which gases are stratified must employ extractive sampling systems or in-situ sampling locations that obtain results that are consistently representative or can be corrected to be representative of the total emissions from the affected facility.

(g) The extractive type of system may accomplish this requirement by using a multipoint sampling probe. The in-situ monitor must be located so that its optical path will view a representative gas sample.

(h) It must be demonstrated that sampling at stratified gas locations gives consistent readings for several plant operating conditions (i.e. points of average concentration do not shift with operating changes).

(i) Pollutant and diluent gas monitoring systems should be of the same type - both extractive or in-situ. If the systems are of different types, the extractive system must use a multipoint sampling probe.

(j) Temperature, velocity, and gas concentration traverses of the stack gas may help to characterize gas stratification. If no stratification is shown at a point less than 8 duct diameters downstream of air in-leakage, procedures for sampling non-stratified gas may be used.

(k) Sampling point locations for the CSEM system may not necessarily be the same as those of the manual stack survey.

(l) There must be an easy and safe access to the monitor for maintenance purposes.

2.9 Quality Assurance Program for Continuous Source Emission Monitoring (CSEM) Systems

After the initial performance evaluation of the CSEM systems, the operator (licensee) should

(a) develop a source specific quality assurance program for each CSEM and submit it to the Department for approval,

(b) perform self-audits periodically, and

(c) take specific corrective actions whenever the CSEM system performance is beyond acceptable limits.

References for Appendix B

1. U.S. EPA Handbook "Continuous Air Pollution Source Monitoring Systems", June, 1979. (EPA 625/6-79-995)

2. "Continuous Emission Monitoring: Design, Operation and Experience" the proceedings of an APCA specialty meeting, November, 1981. (SP-43)

3. "Gaseous Continuous Emission Monitoring Systems Performance Specification Guidelines - EPA-450/3-82-026" issued by the U.S. EPA - Emission Standards and Engineering Division

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